Blackout 2003

Performance of the New England and Maritimes Power Systems During the August 14, 2003 Blackout

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Independent System Operator New England

The People Behind New England's Power

Executive Summary

On August 14, 2003, New England's bulk power system faced its most challenging conditions in more than 30 years of operation. New England's bulk power system and ISO New England operators successfully met that challenge. While a cascading power outage left 50 million people in nine states and one Canadian province without electricity, the lights stayed on in most of New England.

The effects on Massachusetts were confined to small areas in Springfield and the Berkshires, which are directly connected to New York, where the power disturbance had serious impacts. In the rest of New England, the effects were confined primarily to southwest Connecticut and northwest Vermont, which have been identified as weaker links in the New England bulk power system.

Most of New England escaped from a potentially devastating impact due to a number of factors:

- Automatic relays that appropriately shut down "the border" between New York and New England, effectively shielding us from the cascade effect;
- The work of system operators to stabilize the system and keep the lights on;
- A healthy supply of generation resources that enabled New England to produce enough power to be self-sufficient once the region was isolated from the rest of the Eastern Interconnection, which is one of the four interconnections in North America; and
- Close coordination between ISO New England and local utilities to restore power as quickly as possible in the effected areas.

The blackout made two things very clear. One, New England has an established, reliable and competitive electricity system. Two, the national power grid needs to recognize how extensively it is interconnected, much like the country's interstate highway system. As such, New England's stakeholders must continue to work together to seek effective regional solutions to continue the progress New England has made.

Immediately following the blackout, ISO New England made several regional and national policy recommendations, and began studying a series of operational improvements for industry-wide application that will help ensure power system reliability and limit the likelihood of similar events in the future.

I. The Event

On August 14, 2003, a major power outage occurred in the Northeastern United States and Canada. The disruption in service affected communications, transportation, commerce, businesses, and consumers in the impacted regions. Because most of New England was spared, the impact was far less drastic here.

Operating conditions within the New England and Maritime power systems were normal on August 14th despite three straight days of high summer temperatures. Neighboring systems, New York and Quebec, were also operating under normal conditions. Around 12:00 noon (EDT), a series of outages occurred in the northern Ohio area, which ultimately disrupted service on most of the Eastern Interconnection in the north central area of North America. By 4:10 p.m., these events evolved into a cascading power outage that left millions of people in Ohio, Michigan, New York, Ontario, Pennsylvania, New Jersey, Connecticut, Maine, Vermont and Massachusetts without electric service. More than 60,000 megawatts (MW) of electricity was out of service during the height of the outage.

As power systems to the West were continuing to break up, power surged from New England to New York when New York's system destabilized. As a result, the relay protection systems appropriately closed the "electricity border" and New England split away from the collapsing power systems to the west. New England and the Canadian Maritimes were disconnected from the rest of the Eastern Interconnection for nearly ten hours. Nonetheless, New England power system operators were able to continue operating the system so that electricity service could be provided to all areas except portions of Connecticut (southwest and central), Western Massachusetts (sections of Springfield and the Berkshires), Maine (Bangor), and northwest Vermont.

ISO New England's system operators then worked closely with local utilities to restore power as soon as possible. Bangor, Maine lost approximately 11 megawatts (MW) of electricity, which was restored within six minutes. Vermont lost 140 MW, but it was restored within one hour. Massachusetts and Connecticut had approximately 500 MW of manual load shed during the afternoon of the 14th. This process is used in order to maintain the integrity of the system during abnormal conditions by deliberately removing certain customers' electric power. This power was restored in Massachusetts by 6:09 p.m., and in Connecticut, excluding the Southwest area, by 7:15 p.m. Southwest Connecticut was restored by 11:27 p.m.

Because the bulk power system remained largely intact in New England, the day-to-day activities of the vast majority of people in the region were largely unaffected by the event. Most businesses and consumers in New England were generally protected from the more severe economic impacts that were felt in other parts of the country as a result of the outage.

II. Investigations

Immediately following the event, ISO New England began a review to determine the reasons for the limited outages in New England and whether additional steps should be taken to further improve the reliability of New England's power system.

ISO New England participated in the US-Canada Power System Outage Task Force investigations. As part of the investigation, the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), the North American Reliability Council (NERC), Regional Reliability Councils, ISO New England, other control areas and underlying operations centers worked to: analyze the disruption; identify the causes; explain the system responses; direct corrective actions for the future; and enhance capabilities to respond to such events. ISO New England also participated in the Massachusetts Governor's Task Force on Electric Reliability and Outage Preparedness, which has just completed its report of the event. ISO New England has concluded its own independent, initial review of the events and, as a result, has compiled comprehensive recommendations to improve the operational structure of power system management, as well as the power generation and transmission infrastructure in New England, the United States and Canada.

The blackout has underscored the need for appropriate and uniform reliability standards, effective monitoring of compliance, and, most importantly, a reliable bulk power transmission system. The potential for large economic losses during interruption of electricity service requires that steps be taken to ensure system reliability.

This report details ISO New England's findings and recommendations, highlights of which are set forth below.

III. Recommendations

A. National and Regional Standards

The size, shape, authority and responsibility of operations centers at all levels throughout the United States must be clear and coordinated. Operations centers must be able to observe their entire systems and must have adequate analytical tools, operating limits and mechanisms for timely physical action. Additionally, reliability standards and operating procedures should be uniform across the country and they must be enforceable with penalties.

It is best if a single entity – such as ISO New England – with clearly documented responsibilities acts as the final authority for operation of the bulk power system in order to maintain a "one set of hands on the wheel" approach and avoid confusion and inaction. Interdependent operational functions should not be fragmented and distributed to numerous separate entities. Moreover, the criteria used to ensure the reliability of the New England bulk power system should continue as the framework for the system.

B. Restoration Plans

In order to ensure quick and effective restoration of bulk power systems after an outage, operators should engage in extensive testing, maintenance and training of the restoration procedures, including the ability of emergency "quick start" generators to supply additional power while systems get back to normal. Maximizing restoration efforts should include regular review and testing of the circuit breakers that disconnect and re-connect New England to the rest of the power grid to ensure that they are working as designed. Control centers should also review their rolling blackout procedures and verify that they continue to comply with the policies of the NERC.

C. Logistics and Information Technology

Communications, access to information, record keeping, and workspaces in control rooms should be enhanced. This includes improving the ability of operators to gauge the status of the system following a major disturbance and improve their decision-making capability through various hardware and software enhancements. Additionally, devices that record fluctuations and disturbances on the system should be tested and replaced, if needed.

D. Voltage and Frequency Performance

During emergencies such as August 14th, the voltage levels of the electricity traveling along the bulk transmission system must be aligned within a stranded area (an "island") and also realigned with neighboring areas in order for the islanded area to be safely reconnected. Frequency and voltage match requirements should be reviewed and amended, if necessary, to ensure a stable system under both normal and emergency conditions. Generators must operate at a voltage level compatible with the transmission system and there should be a detailed review to determine whether all generators should use "Automatic Voltage Regulators."

E. Further Studies and Reviews

Participation should continue in working groups and study groups that are assessing concerns that have evolved from the event. Additionally, an assessment is needed on the adequacy of back-up power supplies for telephone service in the region.

BLACKOUT REPORT

I. INTRODUCTION

On Thursday, August 14, 2003, at about 4:10 pm Eastern Daylight Time, the largest blackout in the history of the United States and Canada struck a vast area of northeastern North America. In a matter of minutes, some 50 million people lost all electric service. Over 60,000 megawatts (MW) of electric load[1] was interrupted, covering large areas of the states of Ohio, Michigan, New York, and the Canadian province of Ontario, as well as smaller portions of Pennsylvania, New Jersey, Connecticut, Vermont, Maine, and Massachusetts. In some states, power was not restored for two days, and parts of Ontario suffered periodic interruptions for more than a week. Even areas not fully blacked out were affected, such as New England and the Maritime provinces in Canada, which were cut off from the rest of the Eastern Interconnection for almost ten hours.

This report describes the impacts of the blackout on power systems in New England and the Maritimes, and summarizes the stabilization, restoration and reconnection of these power systems to the Eastern Interconnection.

A. Background for Events on August 14th

The bulk power system in New England and the Maritime Provinces in Canada ("Maritimes") are a kind of geoelectrical peninsula to the rest of the North American power system, and specifically the Eastern Interconnection.[2] Quebec, however, operates on its own as an independent interconnection because its only ties to the rest of the Eastern Interconnection are asynchronous, high voltage direct current (HVDC). This means that the only synchronous, alternating current (AC)[3] connections between the New England/Maritimes area and the rest of the Eastern Interconnection are through New York State. With the breakup of the New York system, New England and the Maritimes were isolated.

Prior to the system disruption on August 14th, operating conditions within the New England and Maritimes power systems were normal. Real and reactive generation reserves were adequate.[4] Generator and transmission station voltages were generally within normal limits (voltage at one generating station was about 1-kilovolt (kV) too high). Transmission interface loadings were within limits, in full conformance with first contingency criteria (i.e., the system could sustain the single most critical system disturbance), and were capable of restoring coverage for a second contingency within 30 minutes. Neighboring systems – New York and Quebec – were also experiencing normal operations.

Beginning at about noon on August 14th, conditions on the bulk power system in the northeastern part of Ohio deteriorated. A series of transmission line outages, and the sudden loss of a number of generating units in Ohio and Michigan, ultimately placed the entire Eastern Interconnection in danger,

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[1] Load is the amount of electric power required or delivered at any specified point on a system. *See* "Sidebars" on page 29 for an additional description of load.

[2] The Eastern Interconnection is one of four interconnections in North America. An interconnection, or a synchronous interconnection, is a group of electric systems that are connected together with alternating current (AC) lines. *See* "Sidebars" on page 27 for detailed information on interconnections.

[3] Direct Current (DC) is an electric current that flows steadily in one direction, whereas alternating current (AC) oscillates at a fixed rate of frequency. High Voltage Direct Current (HVDC) ties do not reflect disturbances from one end to the other the way AC ties can. *See* "Sidebars" on page 27 for further analysis of interconnections and DC ties.

[4] Real power refers to the portion of total AC power that does the actual work; its units are "watts." Reactive (or imaginary) power refers to the portion of AC power that maintains the voltage so that watts can work to power equipment; its units are "VARs." A sufficient amount of both power components are needed as part of the generation reserve. *See* "Sidebars" on pages 27-28 for a full explanation of reactive power.

culminating with instability at about 4:10 pm. In essence, major areas of the Midwest, Middle Atlantic States, New England and the Canadian Provinces electrically separated from the rest of the Eastern Interconnection, leaving some areas totally blacked out and other portions operating as electrical "islands."

B. Steps Taken In Response to System Disturbance

The bulk power system in the New England/Maritimes area remained largely intact during this event, and a much smaller number of customers actually lost power supply. A portion of Bangor, Maine was without power for several minutes and small areas of Vermont lost load as voltage sensitive equipment came off line and also when some transmission lines tripped. Areas of Connecticut (in Southwest Connecticut at the Long Mountain/Norwalk area) became disconnected from the rest of New England and collapsed. Also, CONVEX[5] manually shed load in other portions of Connecticut and western Massachusetts, in accordance with Operating Procedures, to successfully stabilize bulk power system conditions and preserve the overall bulk power system in New England and the Maritimes. Because the bulk power system was largely preserved in New England and the Maritimes provinces in this manner, electricity continued to be available so that the day-to-day activities of the vast majority of people in those regions were largely unaffected by the events occurring in other parts of the country.

Severe oscillations did occur on the New England system, however.[6] ISO-NE and satellite system operators worked to prevent further separations, restored service in the blacked out areas of New England, and reestablished ties to New York, which was going through a similar restoration. Through these efforts, New England and the Maritimes were reconnected, or "synchronized," so that their frequencies (cycles per second, or hertz) matched exactly to the frequency of the rest of the Eastern Interconnection.

Most of the 140 MW of load lost in northern Vermont was restored within an hour. Roughly 500 MW of load that had been manually shed in Connecticut and western Massachusetts, with the exception of southwest Connecticut, was restored by 7:15 pm on the 14th, with the system in Massachusetts fully restored by 6:09 pm. By 11:27 pm, essentially the entire southwest Connecticut area transmission was also restored.

An electrical interconnection with New York was reenergized at 1:52 am on August 15th, ending approximately ten hours of separated operation. After synchronization, ISO-NE and New York ISO ("NYISO") operators restored additional New England – New York tie lines, and New England supplied up to 600 MW of emergency power to New York on these ties. Also, as directed by an Emergency Order issued by the United States Department of Energy (DOE) in response to the blackout, New England began delivering emergency power to Long Island, NY via the Cross Sound Cable HVDC facility. Power flows on the Cross Sound Cable ranged from 100 MW to 300 MW. New England was able to provide significant emergency assistance to New York for the next several days, with total exports reaching as high as about 1,500 MW on all available New England-New York tie lines on August 16th . New England was also able to assist Ontario through its interconnections with the New York system.

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[5] Connecticut Valley Electrical Exchange, one of the satellite control operators in New England.

[6] Much of this behavior may have been caused by the large frequency bias obligation required by North American Electric Reliability Council (NERC) standards (1% of forecasted peak load). The normal 1% requirement is used successfully under normal interconnected conditions. However, actual frequency response is about .5 to .6% of forecasted peak load. In an islanding scenario, the control signals sent to those generators providing Automatic Generation Control (AGC) can result in a significant overshoot and then oscillations.

There were three primary reasons why most of New England and all of the Maritimes islanded and survived. First, the New England and Maritimes systems were in secure and robust condition prior to the event. Second, there was a reasonable balance between lost load and lost generation during the event. Third, when power surged from New England towards New York the protection relays near Northfield, MA opened the circuit breakers on the Northfield end of the Northeast – Berkshire tie line. This sent transfer trip signals to the Berkshire and Alps ends of this three terminal line, severing this transmission path between New England and New York.

II. CONDITIONS IN NEW ENGLAND PRIOR TO THE EVENT

As detailed below, the New England region went into the peak hours of the day of the blackout in a strong position. No emergency procedures were in effect or forecasted, and all operating reliability criteria were being met or exceeded. Neither ISO-NE nor any of the Northeast Power Coordinating Council (NPCC) Control Areas were aware of any of the events occurring in the Midwest throughout the day leading up to the cascading outages that occurred shortly after 4:10 pm. Communications with the neighboring Control Areas of New York, the Maritimes (New Brunswick) and Quebec were all normal, and all of the Areas were operating in conformance with criteria.

A. Demand in the Region

New England was in the midst of an extended period of warm and humid summer weather during the week beginning Sunday, August 10, 2003. Temperatures ranged from the mid-seventies to the upper-eighties, with thunderstorms in the daily weather forecasts.[7]

This extended period of warm and humid weather resulted in increasing power consumption throughout the week, with daily peaks in the range of 22,800 to 23,400 MW from Monday to Thursday. The Morning Report for August 14th indicated surplus capacity of 3,138 MW for the 1:00 pm peak hour, with total net exports of 1,539 MW. The peak for the week was actually set on the 14th at 23,347 MW (preliminary) during the hour ending at 4:00 pm – just prior to the blackout. This was about 1.5% above the forecasted load of 23,000 MW.

The 3,138 MW "surplus capacity" is the amount of available generating capacity over and above forecast peak load, plus the net of export and import power, plus the Total Operating Reserve Requirement. Even with demand levels exceeding the forecast by over 300 MW, from a regional perspective, there was more than ample generation available in the New England system.

The net system demand, 23,347 MW, supplied across the four satellite areas at 4:00 pm distributed as follows:

ISO-NE	CONVEX	Maine	New Hampshire	REMVEC[8]
23,347	7,944	1,394	1,731	12,278

B. Inter-Area Transfers

The Inter-Area Scheduled and Actual Interchanges for the hour ending 4:00 pm are shown in the following table. Scheduled imports for the 4:00 to 5:00 pm hour were essentially the same (note that a negative sign indicates a power transfer import into the New England Area).

[7] On Thursday, August 14th, the high temperature in Boston, MA at 4:00 pm was 87 degrees, and the dewpoint was 65°. The high temperature in Hartford, CT was 90 degrees, with a 67° dewpoint.
[8] Rhode Island Eastern Massachusetts and Vermont Energy Control.

NEPOOL		NYISO		NBEPC[9]		HQ[10]	
Actual	**Scheduled**	**Actual**	**Scheduled**	**Actual**	**Scheduled**	**Actual**	**Scheduled**
-1,792	-1,722	376	380	-511	-450	-1,657	-1,652

During the hour ending at 12:00 noon, the transfer limit from New England to New York had been reduced from the forecast of 600 MW down to 400-500 MW in order to protect the Whitehall – Blissville 115 kV K7 line for a stuck breaker contingency involving the loss of the Northfield – Berkshire – Alps 345 kV 312/393 line.

All schedules were being adhered to using normal control performance criteria and no unusual conditions occurred leading up to the event.

C. Operating Reserves

NEPOOL Operating Procedure No. 8 (NOP #8), "Operating Reserve and Automatic Generation Control," is the governing document for reserve criteria in New England. This document details the specific criteria that must be met in preparing for the operating day and real-time operations. The requirement is based on ensuring continued uninterrupted service, and is derived from calculating the largest single source contingency loss, which on August 14th was the Hydro-Quebec Phase II tie at 1,400 MW, plus one half of the second largest contingency loss, which was the Seabrook generating station that was operating at 1,162 MW. Ample Ten- and Thirty-Minute Operating Reserves were carried on August 14th. All requirements were met, and even exceeded, in actual, real-time operations.

The Total Operating Reserve Requirement in New England on August 14 was 1,981 MW.

D. Generating Resources Out of Service

Generation outages and reductions for the hour ending at 4:00 pm on August 14th amounted to approximately 1,600 MW. Of this, 656 MW represented units out-of-service, while the remainder was due to reductions to on-line resources, which were nominal. There were very few planned or unplanned transmission outages in New England prior to the event. The outages were all outside of the area impacted by the blackout; they did not influence events either before or after it, or hinder the restoration efforts that followed.

E. Transmission Interfaces

Power flows on transmission ties to neighboring Control Areas, as well as on critical transmission interfaces within New England, were all operating at or below limits prior to the event.

F. Voltages and Reactive Power

In New England, voltage/reactive Operating Guides call for static shunt devices (i.e., reactors and capacitors) to be dispatched in a manner that proactively establishes and maintains robust voltages

[9] New Brunswick Electric Power Commission.
[10] Hydro-Quebec.

and maximizes the dynamic reactive reserves on generators. This practice promotes the ability of units to respond to system contingencies, thus enhancing overall system voltage/reactive security. Prior to the disturbance, generating station voltages were within normal limits, except for one generating station that was about 1 kV high. Reactive reserves on units and in key areas of New England were ample. All key transmission voltages were within normal limits.

III. ANALYSIS OF THE DISRUPTION

A. System Instability and Separation

On August 14, 2003, beginning at about 12:05 pm and continuing up to about 4:10 pm Eastern Daylight Time, a series of generator and transmission outages occurred, which affected the Eastern Interconnection's ability to serve load in the northern Ohio area, roughly between Toledo and Cleveland. What began as separate independent events ultimately evolved into cascading thermal overloads followed by voltage collapse. Towards the end of this period, at approximately 4:10 pm, the direct ties between northern Ohio and southern Ohio opened, so that power flowing toward northern Ohio shifted to paths running from Indiana up into western Michigan, across to eastern Michigan and then down into northern Ohio. The large magnitude of these flows critically depressed voltages in the middle of the Michigan power system, precipitating a west-east split within the state.

Almost simultaneously with the splits occurring in Ohio and Michigan, the single remaining interconnection between northern Ohio and northwest Pennsylvania tripped, which left eastern Michigan and northern Ohio connected only to the Ontario system. Consequently, power transiently surged from the bulk of the Eastern Interconnection across the Pennsylvania – New York interface, through New York into Ontario, and then through Ontario into the eastern Michigan and northern Ohio areas. At this point, the systems were stressed beyond their stability limits. This caused power angles to jump in New York, power to surge into the radial New England and Maritimes systems, and frequency to rise to 60.3 hertz (Hz).[11] This triggered the action of a Special Protection System (SPS) in New Brunswick to reject roughly 380 MW of generation.

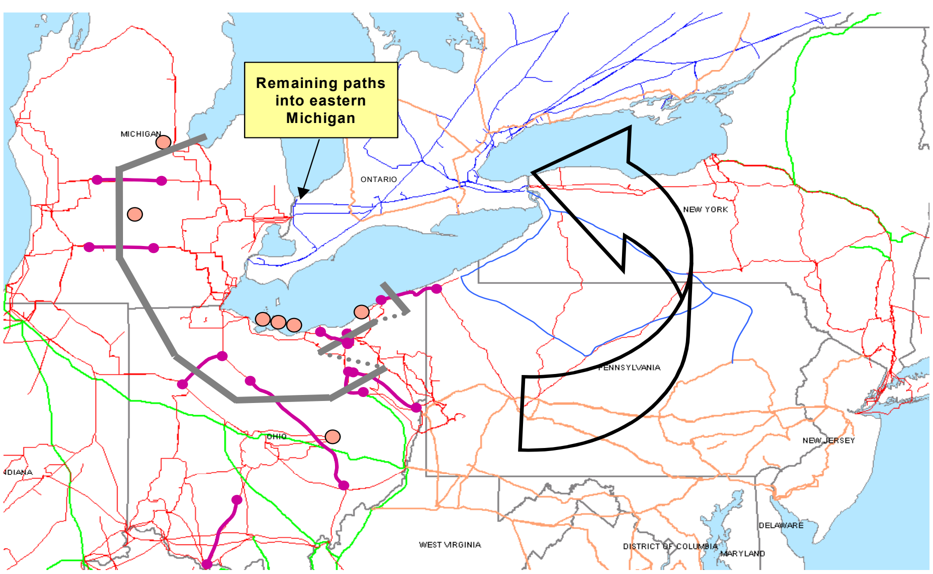

Figure 1 – Summary of Situation at 16:10:38

[11] Normal frequency is 60 hertz.

The magnitude of the power surge from Pennsylvania to New York caused the PJM-NYISO tie lines to trip in rapid succession, thereby separating New York, northeast New Jersey, New England, the Maritimes, Ontario, eastern Michigan and northern Ohio from the rest of the Eastern Interconnection. These systems, in effect, became one large electrical island with power draining towards the eastern Michigan/northern Ohio pocket. Northwestern Ontario, which is tied only weakly to the rest of the province, then shook loose and stayed tied to the Eastern Interconnection through the Manitoba and Minnesota systems. Ontario separated from Michigan and both collapsed.

The Ontario system also separated from New York, but 1,000 MW of hydro generation at Beck (Niagara) and 1,000 MW of hydro generation at Saunders (St. Lawrence) remained radially connected to upstate New York (effectively like a peninsula). This allowed the bulk power system in upstate New York to survive. However, the Hudson Valley below Albany and the New York City area collapsed. Southwest Connecticut and Long Island formed an island, but then separated from each other and collapsed. Most of northeast New Jersey also collapsed.

As instability progressed, a rapid drop in frequency, and an accompanying drop in voltages, in eastern New York led to a massive power surge from New England to New York. This caused circuits that are generally along the New England – New York border to trip, thereby stranding the majority of New England with the Maritimes systems. New York State split into western and eastern islands, with northeast New Jersey and southwest Connecticut still tied to eastern New York.

In brief, most of Ontario and New York's load was lost, along with southwest Connecticut and northeast New Jersey, but the New England/Maritimes island survived.

B. Power Supply to Nuclear Units

A critical concern in blackout events is the provision of off-site AC power sources to nuclear generators, as required by the Nuclear Regulatory Commission. Nuclear units in New England and New Brunswick experienced severe transients during the disruptions that occurred between 4:10 and 4:12 pm. The system split that occurred between New York and New England/Maritimes, along with an even balance between lost generation and demand and robust pre-event conditions, allowed the New England/Maritimes electrical island to survive, preserving AC supplies to the nuclear units. Some nuclear units did drop into "safe modes" operation. More details on the contingencies and system responses that comprise the August 14, 2003 blackout event can be found in the report of the U.S.-Canada Power System Outage Task Force Phase I report.

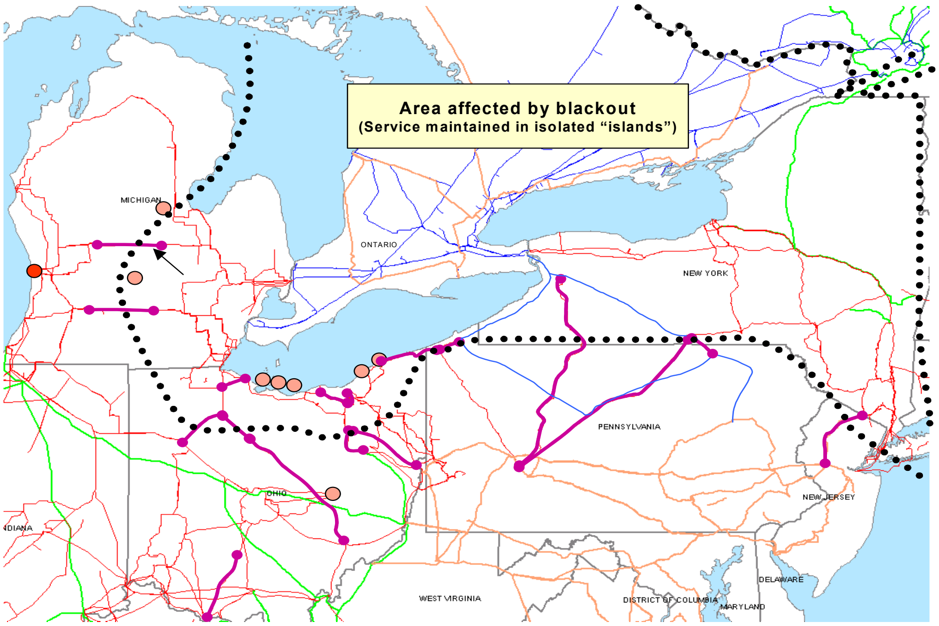

Figure 2 – Cascading Sequence Essentially Complete

IV. NEW ENGLAND/MARITIMES ISLAND

A. Formation of Island

Severe oscillations continued after the SPS-initiated generation rejection in New Brunswick. At 4:10:45 pm, the frequency dropped rapidly and substantially, ultimately reaching its lowest value during the disturbance (59.5 Hz measured in New Brunswick at roughly 4:10:46 pm). Simultaneous with this frequency drop, power surged from New England towards New York, and circuits on or close to the New England – New York border experienced very low voltages. This power surge and frequency drop were in response to the PJM - NYISO separation, and the remaining power deficiency in systems west of New England.

By 4:10:47 pm, protection relays at the Northfield Mountain pumped storage plant near Northfield, MA appropriately interpreted the power surge and accompanying voltage drop as a fault, causing circuit breakers to open the Northfield end of the Northeast – Berkshire tie line. This sent transfer trip signals to the Berkshire and Alps ends of this three terminal line, severing this transmission path between New England and New York.

Similar transient conditions and appropriate circuit trips occurred on other New England – New York tie lines or lines close to the New England – New York border. A slight back up of the split into Connecticut left a portion of southwest Connecticut (later referred to as the Long Mountain/Norwalk area) tied to New York via two circuits, but after roughly 56 seconds these circuits opened and the area collapsed.

The action of the relay protection systems to open, or "trip," the foregoing circuits was appropriate and occurred as it was designed to. In fact, this relay action is one of three reasons why most of New England and all of the Maritimes islanded and survived. Other reasons are the secure and robust state of the New England and Maritimes systems prior to the event, and a reasonable balance between lost load and lost generation during the event.

The following diagram geographically displays where the New England/Maritimes split from New York.

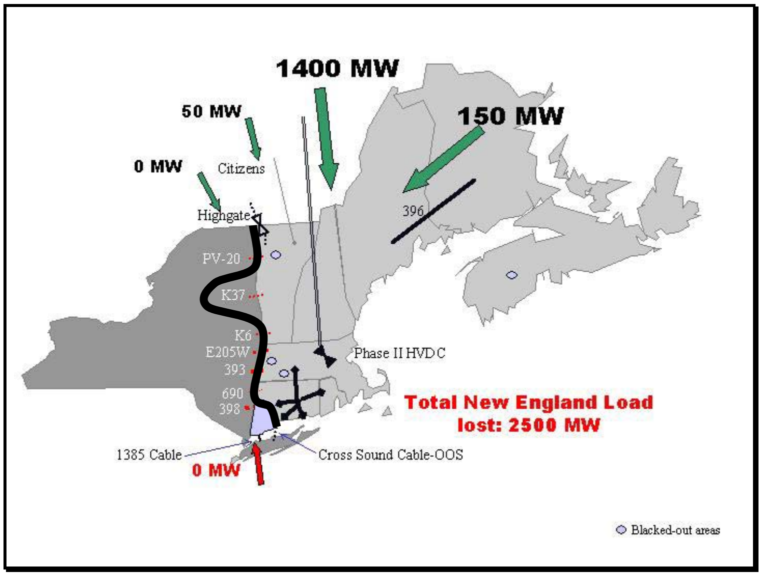

Figure 3 – New England / Maritimes Island

B. Generator Trips in New England

The severe frequency, power and voltage transients experienced during the system disruption caused relay protection to trip roughly 2,800 MW of generation in New England. All of the units/facilities that tripped were either in the vicinity of the split that occurred between New York and the New England/Maritimes systems, or within the Long Mountain/Norwalk area of southwest Connecticut, which temporarily broke off with New York before separating from New York and collapsing.

The vast majority of trips occurred between 4:10 – 4:11 pm, when critical transients were being experienced in New England: a rapid frequency decline, a large power surge to New York, and severe voltage drops in the vicinity of the New England – New York border. All relay protection systems appear to have operated properly for the transient conditions that occurred. Nearly all of the units that tripped were available again for dispatch within a few hours, with minimal generator equipment damage.

Given the prevailing emergency conditions in the Northeast, as many units as possible were brought on as soon as feasible, and they continued to operate into the weekend in order to support reliability and to facilitate the supply of emergency power to neighboring Control Areas – especially New York and Ontario.

C. Load Tripped Automatically

The bulk power systems in New England and the Maritimes are effectively in-series,[12] radial or peninsular to the Eastern Interconnection. Moving west to east from the New York – New England border to the Atlantic coast of Nova Scotia, transient frequency swings induced by events on the Eastern Interconnection become more pronounced. This phenomenon is similar to the amplifying action of a wave traveling down a whip and culminating in a snap. This behavior is evidenced in transient frequency plots recorded in New England, New Brunswick and Nova Scotia. The most severe transient

[12] They are arranged in the electric grid in a way that power flow passes through each system without branching.

frequency dip occurred at approximately 4:10:46 pm, when frequency was roughly 59.6 Hz in New England, 59.5 Hz in New Brunswick, and 59.39 Hz in Nova Scotia. In Nova Scotia, a small amount of underfrequency load shedding[13] occurred automatically at a remote eastern station near Sydney. Although this load shedding was set for 59.3 Hz, it actually operated incorrectly at 59.5 Hz. Because of the malfunction, a new underfrequency load shedding relay was subsequently acquired and installed.

A small amount of automatic underfrequency load shedding also occurred within the Bangor (Maine) Hydro Electric system. Although the transient frequency dip only went down to about 59.6 Hz, some 5% of Bangor load (roughly 11 MW) was set up to be automatically shed if frequency dipped to 59.6 Hz based on an old arrangement between Bangor Hydro Electric and New Brunswick. This requirement was related to 345 kV separations in Maine, which leave the Bangor area load on the islanded Maritimes systems. Service to the affected Bangor load was restored in 6 minutes. Bangor Hydro Electric and New Brunswick have since reviewed the need for this arrangement and have changed the setting to the standard NPCC first level setting of 59.3 Hz.

In Vermont, load was interrupted primarily due to low voltage and the automatic opening of transmission line breakers. The voltage in the northwestern part of Vermont oscillated several times over a period of 4.5 seconds between 0.21 per unit and 1.07 per unit. These voltage swings caused the tripping of voltage sensitive equipment – air conditioners, process motors, fans, compressors, adjustable speed drives, computers, and other power electronic loads. It is estimated that voltage depressions interrupted approximately 130 MW of load.

In addition to voltage sensitive equipment tripping off line, several transmission lines in Vermont also tripped as a result of the low voltage. For example, the radial line between Georgia and Highgate tripped, resulting in a load loss of approximately 9 MW.

Similar severe transient voltage dips occurred in Connecticut, and voltage sensitive loads responded in the same fashion by tripping off and then reconnecting once the voltage stabilized at acceptable levels. Some involved industrial/commercial loads tripped by automatic undervoltage protection.

During the initial minutes of separation from the Eastern Interconnection, changing control modes from tie-line bias in the paused state to flat frequency for the New England Control Area would most likely have enhanced the island performance. Similarly, it is desirable under most circumstances to have the Maritimes Control Area utilize flat tie line control while islanded with New England. This configuration has the potential of minimizing undesirable flows and inter-area oscillations on the limited transmission facility between the Maritimes and New England.

D. <u>Generation/Load Balance</u>

All told, about 3,100 MW of generation tripped in New England and the Maritimes at the time of separation from New York. At the same time, roughly 3,100 MW of demand, comprised of interrupted load and exports, was lost. This even balance of lost generation and lost load within the New England/Maritimes island, along with subsequent governor action[14] and HVDC frequency modulation, resulted in frequency excursions (changes in frequency) that were more moderate than might have been

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[13] This is the process of deliberately removing electrical load from the system when the system frequency declines below a specified value. Generally, its purpose is to return the frequency of an islanded system to 60 hertz by bringing electrical load into balance with generation. It is almost always accomplished by automatic relays, as it was here.

[14] Governors are mechanical or electronic speed controls on all generating units. Their purpose is to increase or decrease the fuel or other energy input to the turbine-generator when its rotational speed or frequency is higher or lower than normal. The "governor action" noted here constituted normal, expected operation.

expected. The widest frequency swings occurred right after the separation, reaching extremes of 60.4 and 59.6 Hz measured at Northfield station. The minimum frequency of 59.6 Hz was well above NPCC's 59.3 Hz setting for the first (10%) block of underfrequency load shedding. Standard underfrequency load shedding within the island was therefore largely unnecessary – unique cases of underfrequency load shedding were explained earlier.

E. Generator and HVDC Tie Performance

Despite some significant frequency excursions during the ten-hour period that the New England/Maritimes system operated as an island, and despite oscillations in the 24 to 56 mHz range, all nuclear, conventional thermal, and hydro units performed acceptably. Frequency modulation on the various HVDC ties to Hydro-Quebec proved valuable in maintaining nominal frequency.

V. STABILIZATION OF THE NEW ENGLAND/MARITIMES ISLAND

Connecticut in general, and southwest Connecticut in particular, are congested load pockets within New England. Because transmission interfaces are limited by voltage performance, reactive dispatch is critical to maintaining reliability. Static devices, such as capacitors, predominantly supply reactive requirements, with dynamic reactive reserves maintained on generators in order to respond to contingencies. The August 14th disturbance separated a significant amount of load in southwest Connecticut from the New England system. The separated area eventually blacked out. The transients experienced during the system separation caused extremely low voltages throughout Connecticut, thus automatically disconnecting a substantial amount of customer load due to the low voltage. In addition, most generators tripped.

Immediately following the separation, the Connecticut transmission voltage reached high levels: more than 385 kV on the 345 kV system, and 130 kV on the 115 kV systems. This was a result of several factors: the static capacitors remaining temporarily in service; load being lost; reduced reactive losses on transmission circuits; and the loss of generation to regulate the system voltage. The Millstone units changed from full reactive output (lagging) during the separation transient, to absorbing VARs (leading) after the separation. Overvoltage protective relays operated, tripping both transmission and distribution capacitors across the Connecticut system. In addition, the load in the part of Connecticut that was still energized began to increase during the first seven to ten minutes following the event. This increase was most likely due to customers restoring load that had tripped during the transient. The load increase, combined with the capacitors tripping, resulted in transmission voltages dropping from high to low voltages within five minutes. The voltage on the 115 kV system fell to approximately 100 to 105 kV.

Simultaneous with the voltage transients, thermal overloads were experienced on the Connecticut and western Massachusetts transmission systems – these resulted from the generation losses in Connecticut and western Massachusetts during the system separation. At 4:16 pm, ISO-NE ordered all fast start generation to come on line. But before the generation could come on-line, increased load aggravated the thermal overloads. The most severely overloaded lines were the Manchester-Hopewell 115 kV line in the Middletown, CT transmission area, and the Breckwood 115 kV transmission cables in western Massachusetts. These lines were operating over their Long Time Emergency (LTE) ratings.[15]

[15] "Long Time Emergency ratings" generally means the facility can operate at that level of current flow for several hours, rather than 15-20 minutes ("Short Time Emergency {STE} ratings"), or continuously ("Normal ratings').

Furthermore, the CONVEX satellite was informed by Middletown Station and West Springfield Station that the voltage was too low for generation to synchronize its frequency with the system. Faced with the thermal overloads and the critically declining voltages, CONVEX ordered manual load shedding. This was completed by 4:40 pm. The load shedding was implemented through SCADA[16] controls from CONVEX and the United Illuminating Company's Dispatch Center. Selectable blackouts occurred in the Springfield and Berkshire area of western Massachusetts, and in central and southwest Connecticut. The load shedding restored the voltage and allowed generation to synchronize. It also reduced thermal overloads to below LTE limits. A total of about 500 MW of load was shed: 400 MW in Connecticut and 100 MW in western Massachusetts. This timely action taken by the CONVEX System Operators stabilized the system in Connecticut and Western Massachusetts. The action was also crucial to preventing further disruption within the New England/Maritimes island.

VI. SYSTEM RESTORATION

A. <u>Communications</u>

Most of the New England power system, and all of the Maritimes, avoided the blackout so communication services in these areas were therefore not affected. All primary and back-up communications systems (public telephone, Automatic Ring Down circuits, microwave, cell phone, radio) at ISO-NE and the Satellite Control Centers remained in-service. This included the NERC Hotline, which is a public telephone system used to connect the various North American Control Areas (including those whose systems had collapsed) for teleconferences to share information and discuss operations.

In the hours and minutes prior to the disruption, when a series of cascading contingencies were occurring in the Ohio area, no calls were made to any of the NPCC's Control Areas, including ISO-NE, either to alert these systems of the critical conditions developing, or to request assistance.

Within minutes of the disruption, the Midwest ISO (MISO) initiated a NERC Hotline conference call of Security Coordinators. Calls continued on a regular basis and included representatives from IMO, NYISO, MISO, Michigan, AEP, ISO-NE, Hydro-Quebec and PJM. These calls helped to identify the extent of the blackout, and facilitated the coordination of restoration.

ISO-NE maintained communications with generating stations and established regular teleconferences with the Satellite Control Centers to share information and coordinate system restoration efforts. Representatives from New Brunswick were included in these calls. Elevated communications were also maintained with neighboring Control Areas, including Hydro-Quebec, New Brunswick, and especially with the severely disrupted NYISO. Satellite Control Centers established communications with neighboring Satellite-level Control Centers, Local Control Centers, Distribution Centers, generating stations and field personnel.

In less than an hour, the split between New York and New England/Maritimes had been identified and displayed on a one-line diagram. This is the critical first step to restoring the system and reconnecting to the rest of the Eastern Interconnection. The collapsed Long Mountain/Norwalk area in Southwest Connecticut was also identified in this time period. The severe disruptions in the IMO, NYISO, Michigan and northern Ohio areas were ascertained along with minor effects on the Hydro-Quebec system.

[16] Supervisory Control And Data Acquisition software.

B. Restoration of Areas in New England

Vermont

In the wake of the severe transients and the system split between Vermont and New York that occurred between 4:10:46 and 4:10:52 pm, there were three 115 kV transmission lines left out of service in Vermont: the Plattsburgh - Sandbar PV20 line; the Georgia - Highgate K21 line (including the Highgate Converter import of 200 MW); and the Bennington - Hoosick K6 line. The Blissville - Whitehall K7 line stayed in service, but lines farther west opened so that Vermont was connected to a radial load pocket in New York for some time following the Vermont-New York split.

The re-closing on the circuits operated as designed. The Bennington - Hoosick K6 line automatically re-closed but tripped out again. The PV20 line opened at Sandbar and remained open. The Plattsburgh end stayed in supplying load at Vermont's South Hero substation. The Georgia - Highgate K21 line successfully re-closed.

At this point, the three Vermont connections to New York were severed and Vermont was relying on other transmission ties to Massachusetts and New Hampshire. One of the first actions to restore the reliability of the Vermont transmission system was to re-start the Highgate converter and import 150 MW into Vermont. Further operator actions included bringing on Vermont thermal generators, arming the under-voltage load shedding scheme, and manning critical substations.

Long Mountain/Norwalk Area

CONVEX restoration efforts can be broken into two parts: restoration of the load that was manually shed to stabilize conditions in western Massachusetts and Connecticut, and restoration of the collapsed Long Mountain/Norwalk area.

Between 4:40 and 5:50 pm, approximately 400 MW of fast-start generation synchronized to the system. Once system security was reestablished, restoration of the load that had been manually shed began at 5:42 pm. CONVEX continued to restore substations through 7:28 pm. Once the substations were reenergized, ISO-NE and CONVEX coordinated with the distribution companies to restore customer load. The load was restored based on the capability of the system.

In the Long Mountain/Norwalk area, CONVEX requested that CL&P and UI man the substations in the affected area. This allowed for manual switching, which was required to ensure that the distribution system was separated from the transmission system. Staffing the substations also allowed a controlled restoration of the transmission system followed by the restoration of customer load.

The Norwalk-Stamford and Danbury areas were tied together again by 9:50 pm. At this point in the restoration, the transmission system was restored except for the area west of Glenbrook Substation. Over the next hour, the restoration of the transmission system west of Glenbrook continued. By 11:23 pm the Connecticut transmission system was restored, except for the New York ties and the 115 kV high-pressure fluid filled cables to Middle River Substation. CONVEX continued working with CL&P throughout the night to energize the distribution buses to restore customer load. By 1:35 am, other than the Middle River Substation, all bulk substation distribution buses were energized.

CL&P was restoring customer load when, at 5:44 am on August 15th, the Southington-Frost Bridge 329 Line tripped due to a conductor splice failure. Along with the lack of southwest Connecticut generation, this compelled CONVEX to order a halt to load restoration at 7:00 am. ISO New England initiated Operating Procedure #4, actions 3, 4, 5, 7, 8, and 9 in Connecticut, and actions 12 and 13 in Southwest Connecticut throughout the day on the 15th, beginning at 6:56 a.m. and ending at 11:45 pm.

The normal morning load pick-up caused the southwest Connecticut transmission system to operate at its transmission transfer limit. Generation restoration throughout the morning prevented CONVEX from having to implement load shedding, but there was no margin to allow continued restoration. By 12:00 noon, generation pick-up provided sufficient transmission system relief to allow load restoration to continue. CL&P restored essentially all load affected by the blackout by the evening of August 15th.

Synchronization to New York and the Eastern Interconnection

In the event of the separation and islanding of the New England and New York power systems, New England Restoration Plans call for re-synchronization of the two systems by energizing the 393/312 circuit from Alps substation in New York to Northfield substation in New England. Synchronizing equipment, generation, and circuit breakers at the Northfield Pumped Storage facility are to be used to effect synchronization.

At 1:53 am on Friday, August 15th, the New York and New England systems were resynchronized with minimal power flow on the 312/393 tie line. This resynchronization effectively reconnected the New England/Maritimes Island to the Eastern Interconnection, since New York had already reestablished its ties to the Eastern Interconnection.

Four New England – New York tie lines were restored in the early morning hours of Friday August 15th; a fifth, the Blissville – Whitehall 115 kV tie line, was restored at 10:43 am on the 18th, once New York's power system was secure. The Norwalk Harbor – Northport 138 kV 1385 circuit could not be restored so soon after the system disruption due to loss of cable insulation pressure. An unsuccessful re-closure attempt raised concerns over the condition of this circuit's Phase Angle Regulator at Northport. But test results proved negative, and the 1385 circuit was returned to service at 1:49 am, August 24, 2003.

VII. EMERGENCY ASSISTANCE TO NEW YORK AND ONTARIO

As additional ties to New York were restored, delivery of emergency capacity and energy increased to as much as 600 MW until the above-referenced 345 kV, 329 line from Frost Bridge to Southington was lost at 5:44 am on August 15th. The loss of the 329-line may have been caused by damage due to the power swings preceding the system separation. After the loss of the 329-line, emergency deliveries were reduced to 150-300 MW, due to thermal restrictions on the New York/New England Interface.

At 3:27 am on the 16th, the 329 line from Frost Bridge to Southington was restored to service. The restoration of the 329 line greatly increased the export capability from New England to New York. At 8:00 am, emergency deliveries on the AC ties began again as loads increased in New York and IMO. By midday, emergency capacity and energy deliveries reached 1,200 MW; they then trended downward to 700 MW by 10:00 pm, at which time deliveries went to zero.

The Cross Sound Cable is an HVDC tie between New Haven, Connecticut and Shoreham, New York on Long Island. This facility had undergone acceptance testing prior to August 14, 2003, but the tie has not been available for dispatch by ISO-NE and the New York ISO due to restrictions imposed by the State of Connecticut. On August 14th, at 11:42 pm, the Secretary for the U.S. Department of Energy declared that an emergency existed due to the blackout, and directed both ISO-NE and the NYISO to require the Cross Sound Cable Company, LLC to operate the Cross Sound Cable in accordance with the ISOs operating and scheduling protocols in order to alleviate the current disruptions in electric transmission service. Pursuant to this order, the operating personnel for the Cross Sound Cable were contacted and directed to make the facility ready to deliver power.

Between 1:00 pm on August 15th and 5:00 pm on the 17th, the cable carried between 100 and 300 MW to aid in the restoration and stabilization of the Long Island Area of the New York grid. ISO-NE and the New York ISO allowed the Cross Sound Cable to come offline by 7:00 pm on August 17th, when the New York ISO no longer required emergency assistance.

A chart detailing the New England to New York AC deliveries, and Cross Sound Cable Emergency HVDC deliveries, appears below. This figure also shows total deliveries to the New York ISO, which reached as high as 1,500 MW. The delivery of this emergency capacity and energy to New York allowed the New York ISO and the IMO operators to maintain reserves on their system and reduce the likelihood of feeder rotations (rotating blackouts) as they continued to restore the blacked out areas of their respective systems.

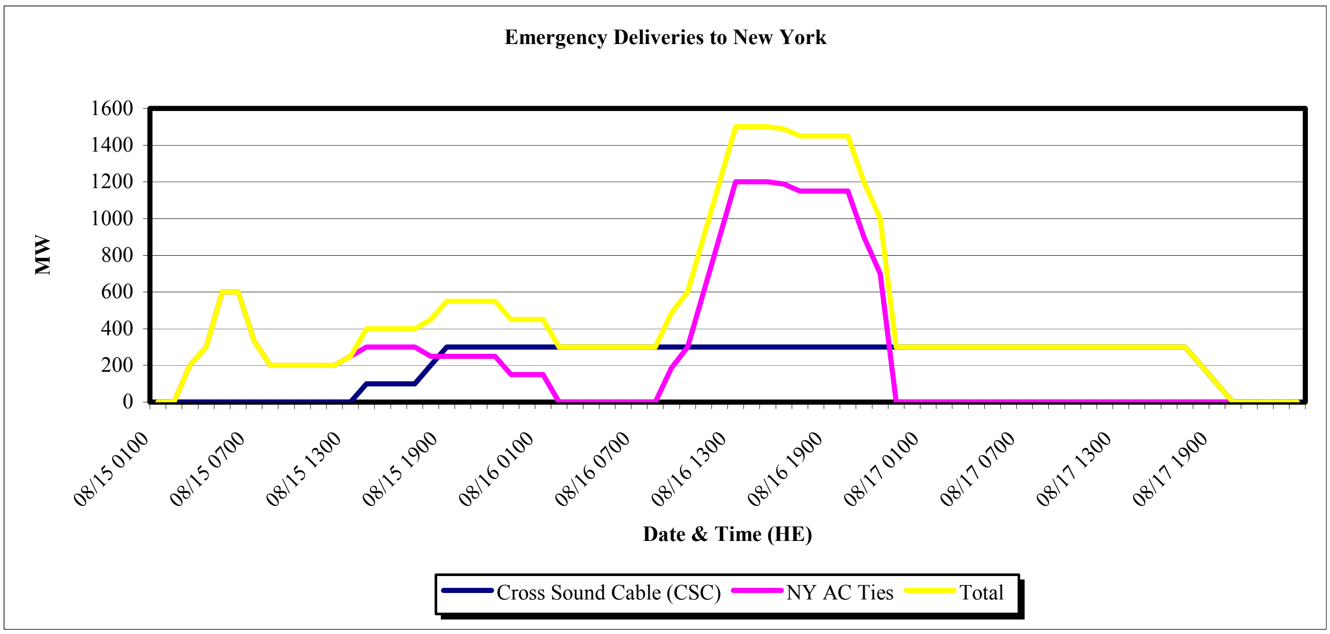


Figure 4 – Emergency Deliveries to New York

VIII. PERFORMANCE OF SOFTWARE AND HARDWARE

ISO-NE has a complex suite of Energy Management System (EMS) tools, which allows the control room operators to view the bulk power system and ensure its secure operation. The fundamental elements of an effective EMS include the ability to gather data from the field and display it in a meaningful way to the system operator. At the ground level, data is gathered at the transmission and generation stations via Remote Terminal Units (RTUs), which transform bulk power indicators into data that is then sent to SCADA centers. Once the data has been gathered at these centers, it is delivered to other users via a dual redundant communications protocol called the Inter-Control Center Communications Protocol (ICCP). This communications protocol allows all of the relevant entities, such as ISO-NE and its Satellite Control Centers, to use the data within their individual EMS systems. Network models are built and updated at each control center, allowing operators to view and operate the bulk power system. Further data refinement and processing is done using advanced application tools such as State Estimation and Security Analysis. These advanced application tools assist the operators in reliable real-time system monitoring when telemetered data is unavailable or incorrect and, perhaps more importantly, also allows the operators to run "what if" scenarios to determine what might happen if certain contingencies were to occur. Using these "what if" scenarios, the system operators can develop contingency plans, including generation shifts, topology changes, phase shifter adjustments, or even load shedding as a last resort, all of which were used in New England on the day of the blackout. The use of these tools is fundamental to system operations in New England, and they were in full use on the day of the disturbance.

For the most part, software and hardware components performed to acceptable levels during the period the New England/Maritimes area was islanded. However, some individual RTUs within the disrupted southwest Connecticut area failed during the blackout. The causes of these failures are unknown. Determination of the causes of these failures, both in the affected area and throughout New England, must be pursued. The blackout's impact on real-time advanced applications at the ISO was substantial for a short period of time. Due to a well-trained network model team, all applications were restored expeditiously in support of control room operators.

After restoration was complete, data collection began. Initially, an outdated and slow software process impeded the data collection. IT staff was able to provide a "work-around" to speed up the data collection process, and ISO-NE was able to collect and distribute the data required for government reporting and analysis. However, it is evident that this data collection process is outdated and cannot meet future collection and analysis requirements. A project is under way to convert to a new Data Historian to meet the needs of the organization.

The most important aspect of EMS performance is the ability of the System Operator to use the data presented in an effective manner, allowing for efficient and reliable dispatch of the power system under normal and emergency conditions. As part of the after-the-fact analysis of the blackout, System Operators and Operations Management were interviewed. What follows are their relevant thoughts associated with EMS performance during the event:

- ISO-NE models all New York equipment at 230 kV and above, including transmission lines, transformers, phase shifters, generating units, and an equivalent of the transmission network at and below 138 kV. However, only analog values are transmitted to ISO-NE, not individual breaker status. The ability to see breaker information in the NYISO footprint for interconnected lines would have allowed operators to more quickly determine the demarcation points of the system separation between New England and New York.
- Operators and Operations Management reported that overview displays of the involved areas would have allowed them to make a faster determination of the affected areas during the blackout.
- Operators and Operations Management recommended that a comprehensive voltage review display be created to allow a simultaneous, one- or two-page review of all critical system voltages on the New England system.
- Operators, Operations Management, Senior Management, and National Reliability organizations have indicated the need to allow operators better ability to determine the status of systems beyond their immediate area of responsibility as a second look to ensure system reliability.

IX. RECOMMENDATIONS

A. Recommendation 1 – The Cure

ISO-NE recommends to the industry that the size, shape, authority and responsibility of Operations Centers throughout the United States must be clear and coordinated with the following underlying principles:

- Infrastructure

  The proposed NERC functional model should reflect the concepts below and ensure that it will not create or promote disjointed operational structures that could create missed responsibilities, operational confusion and inaction.

  - Operations organizations should avoid large "Swiss cheese" territorial footprints.
  - Levels of operations must have clear documented responsibilities with ultimate authority at one entity.
  - Operations Centers must be able to observe their entire system and must have adequate analytical tools, operating limits and mechanisms for timely physical action.
  - Interdependent operations functions should not be fragmented and distributed to numerous, separate entities.

- Reliability Criteria
  - Reliability criteria must be mandatory <u>throughout</u> the industry, especially timely recovery from contingencies, including manual load shedding if needed.
  - National and Regional reliability criteria should be considered minimum requirements.
  - Operating Procedures should be standardized across broader regions.
  - Chief Executive Officers, Chief Operations Officers or Vice Presidents from RTOs, ISOs, Reliability Coordinators, Control Areas, and Transmission Owners should certify their organizational compliance with NERC and any other applicable Regional or Area reliability standards.
  - Reliability Standards should become enforceable nationwide with penalties. An entity with flagrant violations should be sanctioned or considered eligible for removal from the Market.
  - Transmission Owners should maintain their high level of commitment to New England standards regarding vegetation management in transmission corridors.

B. <u>Recommendation 2 – New England Operations Personnel and Infrastructure</u>

Recognizing the continuing effectiveness and clarity of the operations criteria and infrastructure within New England, ISO-NE makes the following recommendations to the Participants:

- The reliability criteria for operating the New England power system presently defined in NEPOOL Operating Procedures and ISO-NE System Operating Procedures (all of which stem from NERC and NPCC criteria) should continue as the framework for power system and market operations and any future changes to Standard Market Design.
- The operational responsibilities and authorities defined in present NEPOOL Operating Procedures, ISO-NE System Operating Procedures and Satellite Operating Procedures should be maintained and reflected in any future infrastructure changes.
- ISO-NE should continue to act as the single entity with final operational responsibility and authority for the overall New England bulk power system. To maintain "a single set of hands on the wheel" and avoid confusion and inaction, key operational authorities of ISO-NE, including final authority over transmission and generation dispatch decisions, should not be segmented, split or delegated to other entities within the New England operations footprint.

Satellite Control Centers should continue to assume and perform responsibilities given to them by NEPOOL and ISO-NE procedures, consistent with a more focused look at their local sub-areas of New England.

C. Recommendation 3 – Voltage/Reactive Performance

The Voltage Task Force of the Master Satellite Heads should:

- Perform a final, detailed review of the plots of generator voltages, confirm the excessive voltage issue found to date, and determine if any other voltage schedule issues exist. Any warranted corrective action should be taken to change voltage schedules or actual voltage operating practices.

ISO-NE has already contacted the generating stations it believed were not operating in automatic voltage regulating mode, confirmed that such was the case, and mutually effected corrective action by switching the regulators from reactive power control to voltage control mode. The Voltage Task Force should perform a final detailed check of reactive power (VAR) plots for all other major units to ensure that automatic voltage regulator responses are proper.

- As part of the "Near-Term Actions to Assure Reliable Operations" transmittal from NERC dated October 15, 2003, ISO-NE has surveyed the status of all generators in New England to ensure that Automatic Voltage Regulators exist and are normally in-service for the resources as required by NEPOOL Operating Procedure No. 14, "Technical Requirements for Generation, Dispatchable and Interruptible Loads."

NEPOOL Participants, Satellite and ISO-NE Control Centers should maintain their high levels of commitment to the following operating procedures and activities related to voltage/reactive security:

- NEPOOL Operating Procedure No. 17 establishing Standards for Load Power Correction and auditing compliance to same;
- Testing of generator reactive power limits;
- NEPOOL Operating Procedure No. 12 – Voltage and Reactive Control including generator voltage schedules and limits. The survey results indicate that a small fraction of small generating resources (<20 MW resources) were found not to have Automatic Voltage Regulators or were unable to operate in the Automatic Voltage Control mode. ISO-NE is reviewing the impact of this finding. If analysis determines that this status is acceptable from a reliability perspective, operating policies and procedures in New England will be revised accordingly. When the analysis is complete, ISO-NE will report the results and ultimate actions to the NPCC.
- Area Voltage Operating Guides, including key transmission station voltage limits and select reactive reserves;
- Interface Voltage Limit Guides and Software Calculators; and
- NEPOOL Operating Procedure No. 14 – Technical Requirements for Generation, Dispatchable and Interruptible Loads.

D. Recommendation 4 – Restoration Plans

NEPOOL Participant, Satellite and ISO-NE Control Centers should maintain their high levels of commitment to the following activities related to system restoration:

- maintenance of ISO-NE and Satellite Restoration Procedures;
- annual System Restoration Exercise;
- annual Black Start Unit Testing;
- maintenance or expansion of the fleet of Black Start Units, including adequate compensation;
- NPCC Compliance testing of Key Facilities for System Restoration;
- NPCC Operator System Restoration Training; and
- ISO-NE and Satellite Operator System Restoration Training.

E. Recommendation 5 – Stabilizing Remaining System(s)

Satellite and ISO-NE Control Centers should maintain their high levels of commitment to: 1) conduct Load Shedding Exercises involving ISO-NE, Satellite and Regional Dispatch Operators every other month; and 2) emphasize throughout System Operating Procedures and Operator training that "any Control Room Operator has the authority to take action(s) required to comply with NERC Policy." The Master Satellite Heads should review their procedures for load shedding. Operators should be able to evaluate and implement load shedding effectively following a major system disturbance.

The System Restoration Working Group of the Master Satellite Heads should note the potential need for actions to stabilize operations within remaining systems in System Restoration Procedures. These actions should include the switching of shunt devices, possible manual load shedding, belaying automatic Desired Dispatch Points and switching to manual dispatch orders, and appropriately opting for flat frequency or tie line bias control depending on the status of tie lines.

F. Recommendation 6 – Frequency Control and Generation Dispatch Within the Island

The following recommendations will be pursued to improve normal interconnected operations and islanding performance:

- The Training, Documentation and Compliance Group will reinforce the steps involved with switching from tie line bias to flat frequency or flat tie control in the early stages of an identified island. The training will include recognition of islanding events and determining what the appropriate control mode would be for the ISO-NE and Maritimes Control Area.
- It is recommended that the computed natural frequency bias response for New England be used with flat frequency control to prevent oscillatory behavior during periods of separation. The System Operations Control Performance Principal Engineer will pursue a waiver of the 1% policy requirement for frequency bias during island conditions, or obtain an appropriate policy interpretation from NERC that will avoid compliance issues upon implementation of this recommendation. The System Operations Control Performance Principal Engineer will work with the Energy Management Systems group to develop software that automatically selects the natural frequency bias, computed by prior studies, as soon as the operator selects flat frequency operation under island conditions.
- An Islanding Operational Support Display will be developed by the System Operations Control Performance Principal Engineer in coordination with the Energy Management Systems group to provide key islanding information to the operator, including the ability to efficiently select and de-select flat frequency AGC control mode operation. The display should also include plots of available and selectable frequency sources distributed throughout the Control Area, as well as breaker status and/or tie line flow data to assist the operator in determining the topological

boundaries of the island. Once the display is ready for operation, the system operators will be trained in its use, and it will be implemented.

- The System Operations Control Performance Principal Engineer will work with the Markets Development Forecast Principal Engineer to further analyze the need for enhancements to the load forecast used in unit dispatch software under islanding scenarios. He will make a final recommendation to the Manager of Operations based upon this analysis.
- A list of increasingly aggressive recommendations to enhance governor response in the ISO-NE Control Area will be led by the System Operations Control Performance Principal Engineer. The following actions will be included:
    - Complete the analysis of substantial frequency deviations that occurred during islanding;
    - Continue ISO-NE's existing frequency response monitoring project at a higher priority;
    - Interview plant personnel responsible for tuning the plant control systems to better understand the physics and control strategies that are deployed, particularly with larger combined cycle facilities;
    - Define requirements for governor response and incorporate them into appropriate criteria.

G. <u>Recommendation 7 – Re-Closing and Switching</u>

The automatic re-closures that occurred on the New England – New York tie lines should be investigated further by the Master Satellite Heads to ensure that these re-closures were: a) appropriate; b) consistent with the normal, steady state design intent of automatic re-closing systems; and c) while not desirable, acceptable for the rare event which occurred on August 14, 2003.

The manual re-connects between the New England/Maritimes island and New York should be investigated and methods to avoid these types of re-connects should be identified. Results should be incorporated into switching procedures and training – and, if appropriate, into System Restoration Procedures by the System Restoration Working Group. The investigation should include such possibilities as: a) requiring the opening of disconnects on circuits that comprise a split between systems; b) changing equipment at all or key transmission stations such that manual re-closures must go through permissive sync-check instead of just manual sync-check; and c) use of automatic paging systems or other means of notification to field personnel to alert them to events involving electrical islanding and increasing sensitivities to the possible need for synchronizations before manual closures of breakers.

The Master Satellite Heads should investigate the methods and procedures used to energize transmission into a collapsed area. Satellite Trainers should incorporate these procedures into the system restoration training.

H. <u>Recommendation 8 – Synchronizing Islands</u>

The NPCC Inter-Area Restoration Coordination Working Group, and the New England System Restoration Working Group, should research the questions raised by field personnel regarding frequency and voltage match requirements for the synchronization of electrical islands. They should establish guides for re-synchronization of islands of various sizes. These guides should be incorporated into System Restoration Procedures.

I. Recommendation 9 – Control Room Logistics

- The System Restoration Working Group should modify the ISO-NE and Satellite Restoration Procedures to: 1) include the assignment of personnel to each Operator Desk to transcribe and reference key decisions and actions that occur during these emergency operating conditions, and 2) call for regular staff meetings within Control Rooms to disseminate information and promote and coordinate activities.
- The Master Satellite Heads should arrange for telephone conversations by technical support personnel (e.g., the Restoration Coordinator) to be recorded on tape.
- The Master Satellite Heads should ensure that work space within or bordering Control Rooms and used by support personnel during system emergencies is adequate, with appropriate computer terminals accessing real-time software and data.
- ISO-NE and Satellite personnel should create "Restoration Packs" similar to the "Evacuation Packs" used when Control Rooms evacuate to Back-Up Control Centers. These Restoration Packs will facilitate response to system blackout events by providing rapid and easy access to needed information and equipment.
- To facilitate communications between the Satellite and ISO-NE Control Centers, the Master Satellite Heads should consider use of a continuously open teleconference line during emergencies and investigate the use of video conferencing.

J. Recommendation 10 – Software/Hardware Performance

The ISO New England Energy Management Systems Department and the System Operations Department should jointly design, develop, deliver and train on the following tools to improve the ability of operators to identify precisely the status of the system following a major disturbance:

- Working with the New York ISO (NYISO), immediately procure information regarding the status of all breakers two busses west of the interconnection points of the New England and New York Control Areas.
- Design and implement overview displays for all of the dispatch areas observable in the Unit Dispatch Software, including Maine, New Hampshire, Vermont, Mass Boston, Northeast MA, Southeast MA, Western MA, Central MA, Rhode Island, Southwest Connecticut, and Connecticut. These overview displays must include station identification, voltages, line designation, line flows and direction, and be linked to the individual substations. These overview displays should be capable of being used across real-time and study applications, including: study powerflow and security analysis; state estimation and SCADA; and real-time contingency analysis. Finally, the displays for the advanced study applications should allow the operator to view conditions in both pre- and post-contingency modes on the same display, and violations of the Normal, LTE and STE ratings should be color coded to allow operators to see overloads.
- Design and implement an overview display of system voltages similar to the "Voltage and Reactive Surveys" displays within Appendix B of NEPOOL Operating Procedure No. 12, Voltage and Reactive Control. This display should provide the operator with critical station voltages throughout the New England system. It should include Heavy and Light Load schedules, Maximum and Minimum allowable voltages, and the desired voltage schedule for individual facilities. The display should also detail the leading and lagging capabilities of critical generators on the interconnection, and provide alarms to operators if any of the limits are violated.

- Design and implement Interconnection Monitor displays in New England for the following Control Areas: NYISO, New Brunswick and the Maritimes, TransEnergie, the Independent Market Operator of Ontario (IMO), and PJM Classic. These displays should include the following information and be similar to the ISO-NE System Summary display: ACE, last ACE crossing, Load, Total Generation, Interchange, Reserve Requirements vs. Instantaneous Actual Reserves, Frequency, and Critical Interface Limits vs. Actual Critical Interface Flows.
- The System Architecture and Technology Department, working with System Operations, should investigate the feasibility and propriety of installing operator visualization tools such as "Power World" or other similar programs to graphically display system information in a more user-friendly format.
- The Information Technology group should continue with its efforts to procure a new data historian tool, and implement the new tool as soon as possible.

The Master Satellite Heads should charge appropriate IT staff to; 1) discern the reasons for the hardware/software failures in the Midwest that were major contributors to the cause of the blackout, 2) determine if the infrastructure of Satellite and ISO-NE Control Centers are susceptible to similar failures, and 3) if so, recommend mitigating actions.

The Master Satellite Heads should charge the New England Data Communications Task Force to investigate the reasons for failures of the RTUs, and/or transmittal of the RTU data to the SCADA and Satellite Control Centers. The Task Force should recommend action geared to avoid the failures under similar circumstances in the future.

K. <u>Recommendation 11 – Transient Recording Devices</u>

ISO-NE System Planning personnel and the NEPOOL Stability Task Force should review the effectiveness and adequacy of transient recording devices in New England, and implement any warranted change-outs or additions.

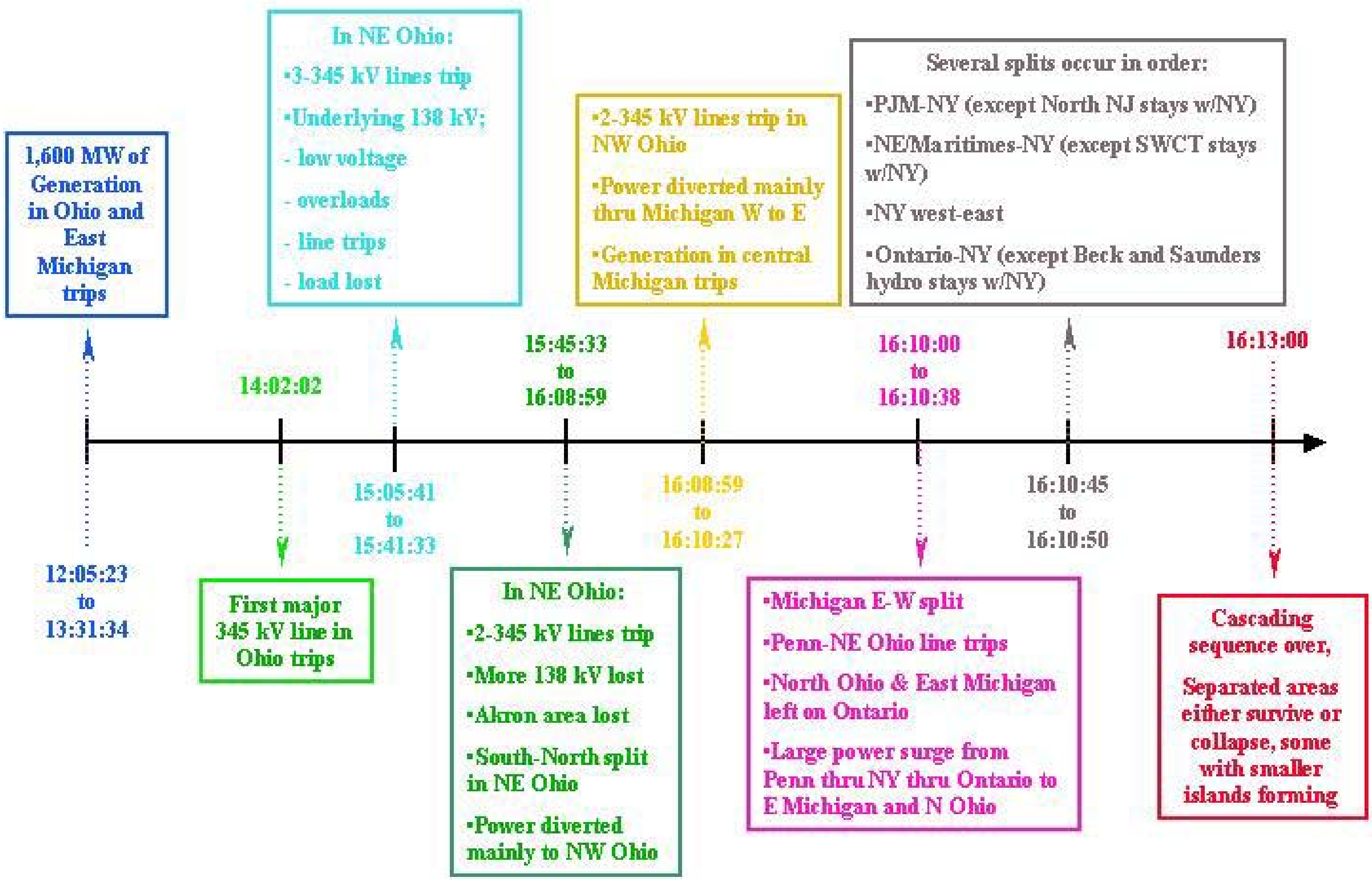
L. <u>Recommendation 12 – Follow up Studies - Telephone Service, southwest Connecticut Split, Simulation of the Event</u>

In a collaborative effort, the Master Satellite Heads and ISO-NE System Planning personnel should work with telephone service providers to assess the adequacy of back-up power supplies for telephone service, and recommend any warranted action to secure these back-up power supplies.

Personnel from Transmission Owners and ISO-NE Near-Term Transmission Reliability and System Planning departments should maintain participation in studies conducted by the MEN Operations Studies Working Group and NPCC Study Groups (e.g., SS-38) to re-create and assess the August 14, 2003 event.

Furthermore, ISO-NE System Planning should determine how the future installation of the 345 kV transmission loop in Southwest Connecticut would have affected the system separation that day.

August 14th Blackout Timeline



SIDEBARS

Interconnections

An "interconnection" or "synchronous interconnection" is an electric system or group of systems, all of which are connected together with alternating current (AC) lines. Anything that happens anywhere on an interconnection is felt everywhere else. A major system disturbance in Missouri, for example, could have a significant adverse effect in New England, or vice versa. The generating units in an interconnection are said to be "in synchronism."

An interconnection is, quite literally, a single large machine.

Power flows in an interconnection via all paths, inversely proportional to the impedance of each path. The lower the impedance of a path, the more power will flow that way; the higher the impedance of a path, the less power will flow that way. But, all lines will be affected by every power transaction or contingency.

There are four interconnections in North America: the Eastern Interconnection, the Western Interconnection, the ERCOT (Electric Reliability Council of Texas) Interconnection, and the Quebec Interconnection. These are connected to each other with high voltage direct current (HVDC) ties. DC ties do not respond to changes on the system the way AC ties do – what happens on one side of an HVDC tie does not affect systems on the other side. Thus, a disturbance in California would not be felt in New York, because they are portions of different interconnections.

Nevertheless, power transfers can be made from one interconnection to another over the HVDC ties. This is how Hydro-Quebec is able to sell power to New England over the Highgate and Phase II HVDC ties, even though the two systems are in different interconnections. Another characteristic of HVDC ties is that they are fully controllable; operators can set a particular power flow, and the tie will continue to carry that amount, regardless of what may be happening on other facilities.

Note: Some people consider Quebec to be a part of the Eastern Interconnection because of its large HVDC tie capacity and significant power sales to its neighbors. Although this may be a commercial reality, it is not technically correct. There are no synchronous ties between Quebec and the Eastern Interconnection – a contingency on one system does not have an effect on the other, beyond the possible reduction or termination of flows on HVDC ties.

Reactive Power/VARs

Alternating current power has two components: real or active power (WATTs) and imaginary or reactive power (Volt Amperes Reactive, or VARs). The two are related in the way real and imaginary numbers are related in algebra. In brief, real power does the work – it lights the fluorescents, runs the air conditioners, and powers the computers. Reactive power does no work, but it's absolutely essential in holding up voltages. If a system has an inadequate supply of reactive power (too few VARs), voltages will go down. Too much reactive power (too many VARs) causes voltages to rise.

VARs cannot be transmitted any significant distance; they generally must be produced locally.

VARs are produced by generators, synchronous condensers, capacitors (or capacitor banks), and transmission lines (capacitive effect – or "line charging"). VARs are consumed by the customers' electrical load, series reactors, transmission lines (inductance – creating a magnetic field), generators and synchronous condensers.

In December 1978, the entire national grid in France collapsed because of insufficient reactive power – not enough VARs.

Stability

"Stability" is the property of an AC electric power system by virtue of which it will attain a new steady state condition following a disturbance. Instability occurs when a new steady state cannot be attained because the disturbance is beyond the restorative powers of the system. Reliability standards generally specify that the system must remain stable for any one of a list of specified contingencies.

Power flow is related to voltages, and the relative "power angles" of generators. The power angle is what actually makes power flow; the greater the difference in angle between two generators, the more the power will flow between them. More precisely, power flow is a function of the trigonometric *sine* of the difference in power angle. In its most fundamental (and admittedly oversimplified) form, instability occurs when the power angle between adjacent generators, or between groups of generators, exceeds 90°. Instability normally occurs in a matter of seconds.

The sine of the difference in power angle is directly proportional to the power flow, and inversely proportional to the voltages on the system. It is also directly proportional to the equivalent impedance between the generators or groups of generators. Thus an increase in power flow, a decrease in voltage, an increase in equivalent impedance – or any combination of these – will increase the angle and make the system less stable. A contingency or combination of contingencies like those that occurred in the Midwest on August 14, 2003 has all three effects.

When systems become unstable, power (both WATTs and VARs) typically surges back and forth between the two groups of separating generators as the relative power angle goes through 90°, 180°, 270°, and so on. This phenomenon is sometimes referred to as "slipping poles." Voltages approach zero at a locus of points on the transmission system somewhere between the two groups (recall that the sine of 180° is zero). Protective relays interpret these extremely low voltages as faults, and open circuit breakers, as they're designed to do, to clear the apparent short circuits. Thus the systems separate electrically, forming electrical "islands." On August 14^{th}, several such separations occurred, one of which resulted in formation of the New England/Maritimes island.

Stability studies involve the simulation of the dynamic response of the system, particularly the generators, to sudden contingencies. They are always based on specific steady state load flow (power flow) conditions. Stability (or instability) is normally judged by examining plots of the power angles of the various generators vs. time. In a stable case, the generator power angles will oscillate, but settle at a new equilibrium. In an unstable case, they will diverge, usually quite dramatically.

Transmission Transfer Capability

The goal of establishing Transmission Transfer Capabilities (TTCs) is to define the maximum amount of power which can be transmitted from one part of the system to another – without instability, transmission overloads, low voltages, or loss of customer load. In concept, the system must remain intact:

1) without a contingency;

2) following the "worst single contingency" (often referred to as the "n-1" criterion) – this requires the examination of the effect of loss of any single element, or loss of multiple elements from a common contingency.

NERC, Regional Reliability Councils, ISOs, and local organizations establish "standards" or "criteria" for planning and operations. Usual specifications include that the system must be within appropriate thermal and voltage limits, and remain stable, for the specified contingencies. Northeast Power Coordinating Council (NPCC) criteria are somewhat more stringent than NERC's. Most of NPCC's Areas have their own criteria, each consistent with NPCC's and NERC's as minimum requirements, but more stringent in some (though different) respects.

Load

The Glossary of the International Council on Large Electric Systems (Conseil International des Grandes Réseaux Électriques, or CIGRE) defines "load" as follows: "The amount of electric power required or delivered at any specified point or points on a system (sometimes referred to as demand)." It is the instantaneous electrical demand – energy consumption per unit time – and can refer to real or active power (watts), imaginary or reactive power (VARs), or both.